United States Environmental Protection Agency
Region 10, Office of Air, Waste and Toxics
AWT-107
1200 Sixth Avenue, Suite 900
Seattle, Washington 98101

Permit Number: R10NT502100
Issued: February 9, 2012
AFS Plant I.D. Number: 41-065-E0001

Non-Title V Air Quality Operating Permit

Project: PSD Avoidance Limits for New Biomass-Fired Electrical Generating Plant

is issued in accordance with the provisions of 40 code of federal regulations (CFR) § 49.139 and applicable rules and regulations to

Oregon Bioenergy, LLC

for operations in accordance with the conditions listed in this permit, at the following location:

Warm Springs Indian Reservation
5000 Ikiutan
Warm Springs, Oregon 97761

Latitude: 44° 47' 18.22" W
Longitude: 121° 13' 34.97" W

Plant Contact: No on-site staff yet

Facility Contact: John Rivers
Project Manager
Oregon Bioenergy, LLC
10800 NE 8th Street, Suite 320
Bellevue, WA 98004
Phone: 425-457-7486
Email: johnr@theNESCOgroup.com

A technical support document that describes the bases for conditions contained in this permit is also available.

Krishna Viswanathan, Manager
Federal and Delegated Air Programs Unit
U.S. Environmental Protection Agency (EPA), Region 10

02/09/2012
Date

1. General Conditions

1.1 Construction and Operation. The permittee is authorized to construct and operate the emission units listed in Table 1, at the location identified on Page 1 of this permit, and consistent with the representations in the permit application and subject to the conditions in this permit.

Table 1 – Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electrical Generation Plant
List of Emission Units

ID	Description	Make and Model	Rating[a]
OB-1	Fluidized Bed Boiler	Energy Products of Idaho No model designation – custom built for project site. Equipped with SNCR, multiclone, baghouse and acid gas control dry injection system.	518.4 MMBtu/hr with 5 distillate fuel burners, four rated at 50 MMBtu/hr each, and 1 rated at 15 MMBtu/hr
OB-2	Cooling Tower	EvapTech EC430-336K, Equipped with DriAir 80 Drift Eliminator	33,966 gal/min[b]
OB-3	Ash Storage and Handling Activities	Unspecified, equipped with three baghouses	Varies
OB-4	Ash Storage and Handling Activities	Unspecified, equipped with baghouse	Varies
OB-5	Limestone Storage and Handling Activities	Unspecified, equipped with baghouse	Varies
OB-6	Emergency Fire Pump Engine,	John Deere, JU6H-UFADP8 6-cylinder, turbocharged, raw water aftercooling, rated speed 1760 rpm	220 hp
OB-7	Emergency Generator Engine,	Cummins QSK60-G6 NR2 16 cylinder, turbocharged and low temperature aftercooled, rated speed 1800 rpm	2922 hp
OB-8	Diesel Fuel Tanks (four tanks)	NA	25,000, 2,500, 800 and 300 gallons
OB-9	Gasoline Fuel Tank	NA	1,000 gallons

a Permit conditions may limit operation to less than rated capacity.
b This flow rate is recirculated 6 times.

1.2. Compliance Required. The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Air Act.

1.3. Compliance with Other Requirements. Compliance with the terms of this permit does not relieve or exempt the permittee from compliance with other applicable federal, tribal, state, or local laws or regulations.

1.4. Relaxation of Enforceable Limitation. At such time that this project becomes a major modification solely by virtue of relaxation in any enforceable limitation on the capacity of the modification otherwise to emit a pollutant, such as restriction on hours of operation, then the requirements of 40 CFR 52.21(j) through (s) shall apply to the modification as though construction had not yet commenced on the modification.

1.5. **Expiration of Permit.** This permit shall become invalid if construction is not commenced within 18 months after the effective date of this permit, construction is discontinued for a period of 18 months, or construction is not completed within a reasonable time.

1.6. **Good Operating and Maintenance Requirements.** At all times, including periods of startup, shutdown, maintenance and malfunction, the permittee shall, to the extent practicable, maintain and operate each emission unit, including any associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions and considering the manufacturer's recommended operating procedures. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

2. OB-1: Fluidized Bed Boiler

2.1. **Nitrogen Oxides (NOx) Emission Limit.** NOx emissions from the fluidized bed boiler shall not exceed 225.76 tons per year (tpy) as determined on a rolling 12-month basis.

2.2. **Carbon Monoxide (CO) Emission Limit.** CO emissions from the fluidized bed boiler shall not exceed 205.23 tpy as determined on a rolling 12-month basis.

2.3. **Particulate Matter (PM) Emission Limit.** PM emissions from the fluidized bed boiler shall not exceed 36.94 tpy as determined on a rolling 12-month basis.

2.4. **Particulate Matter With an Aerodynamic Diameter Less Than 2.5 microns ($PM_{2.5}$) Emission Limit.** $PM_{2.5}$ emissions from the fluidized bed boiler shall not exceed 36.94 tpy as determined on a rolling 12-month basis.

2.5. **Particulate Matter With an Aerodynamic Diameter Less Than 10 microns (PM_{10}) Emission Limit.** PM_{10} emissions from the fluidized bed boiler shall not exceed 36.94 tpy as determined on a rolling 12-month basis.

2.6. **Sulfur Dioxide (SO_2) Emission Limit.** SO_2 emissions from the fluidized bed boiler shall not exceed 34.89 tpy as determined on a rolling 12-month basis.

2.7. **HCl Emission Limit.** HCl emissions from the fluidized bed boiler shall not exceed 9.50 tpy as determined on a rolling 12-month basis.

2.8. **Fuel Limitation.** With the exception of No. 2 distillate fuel, which shall be used only for boiler startup, the permittee shall only combust residues and waste from agriculture or forestry industries in the boiler.

2.9. **Steam Production Limit.** The permittee shall not use the fluidized bed boiler to produce steam in excess of 1,541,769 tons of steam during any rolling 12-month period.

2.10. **Distillate Fuel Combustion Limit.** The permittee shall not combust in the fluidized bed boiler, distillate fuel in excess of 60,000 gallons during any rolling 12-month period.

2.11. Distillate Fuel Sulfur Limit. The permittee shall not combust in the fluidized bed boiler, distillate fuel with a sulfur content in excess of 0.0015 per cent by weight.

2.12. Operation of Control Equipment. At all times that the fluidized bed boiler is in operation, except for the first 10 hours of each startup event, the SNCR system shall be in full operation.

2.13. Operation of Control Equipment. At all times that the fluidized bed boiler is in operation, the exhaust of the boiler shall be directed to an acid gas control dry injection system, a multiclone and a baghouse, all of which shall be in full operation.

2.14. Triboelectric Monitor. The permittee shall install, calibrate, maintain and operate a triboelectric bag leak detector on the baghouse serving the fluidized bed boiler. The triboelectric detector shall be in full operation at all times that the fluidized bed boiler is in operation.

2.15. Diesel Fuel Meter. The permittee shall install, calibrate, maintain and operate a nonresettable, totalizing fuel meter on the distillate fuel inlet to the fluidized bed boiler.

2.16. Fuel records. For each distillate fuel delivery, the permittee shall maintain a record of the actual sulfur content of the distillate fuel.

2.17. Process and Control Monitoring. The permittee shall install, calibrate, operate and maintain (in accordance with manufacturer specifications) equipment necessary to measure and record the steam production rate (pounds per hour (lb/hr)), steam pressure (psig), steam temperature (°F), excess oxygen and SNCR operating parameters including temperature and reagent injection rate, acid gas control dry injection system operating parameters, including temperature and sorbent injection rate. Boiler process and control data shall be recorded on date stamped strip charts, circular charts or electronic data logs.

2.17.1. At least annually, the permittee shall verify and document the accuracy of the steam production rate monitoring equipment in accordance with manufacturing specifications. The first annual accuracy determination shall be performed within 60 days after initial startup of the boiler.

2.18. Boiler Emission Monitoring. The permittee shall install, certify, calibrate, maintain and operate a continuous emission rate monitoring system(s) (CERMS) for measuring and recording separately the emission rate (lb/hr) of CO, NOx and HCl from the fluidized bed boiler. The CERMS for the boiler shall be installed and operational beginning on the date that the boiler begins operation. A CERMS includes a continuous emission monitoring system for each of the three pollutants and a stack flow monitoring system with an automated data acquisition and handling system for measuring and recording pollutant concentration (parts per million (ppm)), stack volumetric gas flow (standard cubic feet per hour (scfh)) and pollutant mass emissions (lb/hr) discharged to the atmosphere from the boiler.

2.18.1. The permittee shall operate and record data from the CERMS during all periods of operation of the boiler. All periods of boiler operation during which CERMS data for any one or more pollutant is unavailable shall be recorded.

2.18.2. Each CERMS shall be designed, installed, calibrated and operated as follows:

2.18.2.1. The CERMS shall be installed such that representative measurements of the total emissions of each pollutant from the boiler can be obtained.

2.18.2.2. A minimum of one cycle of operation (sampling, analyzing and data recording) shall be completed for each successive 15-minute period. One-hour average pollutant emission rates (lb/hr) measured by the CERMS shall be computed from four or more data points equally spaced over each one-hour period except that a one-hour average pollutant emission rate may be computed from two or more data points separated by a minimum of 15 minutes if other data point(s) are unavailable as a result of the performance of calibration, quality assurance or preventive maintenance activities.

2.18.2.3. The CERMS continuous emission monitoring system shall automatically check the low-level (between 0% and 20% of span) and high-level (between 50% and 100% of span) calibration drifts at least once daily in accordance with the manufacturer's recommended procedure. The system shall, at a minimum, be adjusted whenever either the daily low-level or high-level drift exceeds 2.5% of the span for the CO and NOx systems and 5% of the span for the HCl system. The system shall allow the amount of excess drift to be quantified and recorded. The system span may be adjusted, when needed to prevent span exceedances from occurring or inadequate measurement accuracy, with prior written approval by EPA Region 10.

2.18.2.4. The CERMS stack flow monitoring system shall automatically check the low-level (between 0% and 20% of span) and high-level (between 50% and 70% of span) calibration drifts at least once daily in accordance with the manufacturer's recommended procedure. The system shall, as a minimum, be adjusted whenever either the daily low-level or high-level drift exceeds 3% of the span. The system shall allow the amount of excess drift to be quantified and recorded. The system span may be adjusted, when needed to prevent span exceedances from occurring or inadequate measurement accuracy, with prior written approval by EPA Region 10.

2.18.3. At least 90 days prior to initial startup of the boiler, the permittee shall develop a CERMS selection and quality assurance plan. At a minimum, the plan shall include:

2.18.3.1. Proposed span for the continuous emissions monitoring systems for each pollutant;

2.18.3.2. Proposed span for the stack flow monitoring system:

2.18.3.3. Proposed instrument selection and instrumental methods to be used for the CERMS;

2.18.3.4. Proposed quality assurance and accuracy determination procedures, methods and schedules similar in scope to Procedure 1 in 40 CFR 60, Appendix F, and Performance Specifications 6 in 40 CFR 60 Appendix B, and applicable specifications and test procedures in 40 CFR 75 Appendices A and B.

2.18.3.5. Proposed emissions determination procedures to be used in the event that data is not available from the CERMS.

2.18.4. The RATA for the CERMS shall be conducted at least once in every eight calendar quarters and the CGA or RAA may be conducted in up to seven of eight calendar quarters but in no more than seven quarters in succession.

2.18.5. The CERMS shall be installed in conformance to the CERMS selection and quality assurance plan, as approved by EPA.

2.18.6. Quarterly CERMS accuracy determinations shall be performed and recorded in accordance with the quality assurance plan required in Condition 2.18.3. The first quarterly CERMS accuracy determination shall be performed within 60 days after initial startup of the boiler.

2.18.7. The CERMS is considered certified when the first quarterly accuracy determination, that is acceptable to EPA, is completed.

2.19. Testing and Evaluation Facilities. Facilities for performing and observing the emission testing and continuous monitoring system performance evaluations shall be provided that meet the requirements of 40 CFR 60.8(e) and Reference Method 1 in 40 CFR Part 60, Appendix A.

3. OB-2: Cooling Tower

3.1. Operation of Control Equipment. At all times that the cooling tower is in operation, the cooling tower shall be equipped with a fully operational DriAir 80 drift eliminator.

3.2. Control Equipment Specification. The permittee shall select and use a DriAir 80 drift eliminator that has a drift rate of no greater than 0.001% of water flow rate.

3.3. Operations Log. The permittee shall maintain a log of each time that additives are added to the water stream directed to the cooling tower. The log shall identify the material and quantity added to the water.

4. OB-3: Fuel Storage and Handling Activities

4.1. Operation of Control Equipment – Truck Dump Baghouse. At all times that fuel for the boiler is being unloaded or dumped at the facility, the truck dump baghouse shall be in full operation in order to control dust generated by the unloading activities;

4.2. Operation of Control Equipment – Screen Building Baghouse. At all times that fuel screening operations are being conducted, the screen building baghouse shall be in full operation in order to control dust generated by the screening activities;

4.3. Operation of Control Equipment – Boiler Metering Bin Baghouse. At all times that fuel is being discharged into the boiler metering bins, the boiler metering bin baghouse shall be in full operation in order to control dust generated by the fuel discharge into the bins.

4.4. Control Equipment Specification. The permittee shall select and use a baghouse for each of the truck dump activities, the fuel screen building and the boiler metering bins that has an exhaust grain loading of no more than 0.01 grains/dry standard cubic feet (dscf).

4.5. Control Equipment Specification. The permittee shall select and use a baghouse for each of the truck dump activities, the fuel screen building and the boiler metering bins that has a fan with the following ratings:

Truck dump baghouse:	no greater than 57,600 cfm
Screen building baghouse:	no greater than 27,600 cfm
Boiler metering bin baghouse:	no greater than 6,120 cfm

5. OB-4: Ash Storage and Handling Activities

5.1. **Operation of Control Equipment.** At all times that the fluidized bed boiler is in operation, the pneumatic transport air for the ash pickup system shall be exhausted to a baghouse connected to the bin vents on the ash storage container.

5.2. **Control Equipment Specification.** The permittee shall select and use a baghouse for the ash handling and storage system that has an exhaust grain loading of no more than 0.02 grains/dscf, and that is fed by a fan with rated at no greater 3,000 cfm.

6. OB-5: Limestone Storage and Handling Activities

6.1. **Operation of Control Equipment.** At all times that limestone is being unloaded at the facility or the limestone storage bin is being loaded, the pneumatic transport air shall be exhausted to a baghouse connected to the bin vents.

6.2. **Control Equipment Specification.** The permittee shall select and use a baghouse for the limestone handling and storage system that has an exhaust grain loading of no more than 0.02 grains/dscf, and that is fed by a fan rated at no greater than 720 cfm.

7. OB-6: Emergency Fire Pump Engine

7.1. **NOx Emission Limit.** NOx emissions from the emergency fire pump engine shall not exceed 0.02 tpy as determined on a rolling 12-month basis.

7.2. **CO Emission Limit.** CO emissions from the emergency fire pump engine shall not exceed 0.07 tpy as determined on a rolling 12-month basis.

7.3. **Operating Limit.** The permittee shall not use the emergency fire pump engine in excess of 100 hours during any rolling 12-month period.

7.4. **Operations Log.** The permittee shall maintain a log of each time the emergency fire pump engine is operated. The log shall consist of the time the engine was started, the average operating load during that operating event and the time that operation ceased.

8. OB-7: Emergency Generator Engine

8.1. **NOx Emission Limit.** NOx emissions from the emergency generator engine shall not exceed 0.18 tpy as determined on a rolling 12-month basis.

8.2. **CO Emission Limit.** CO emissions from the emergency generator engine shall not exceed 1.71 tpy as determined on a rolling 12-month basis.

8.3. **Operating Limit.** The permittee shall not use the emergency generator engine in excess of 100 hours during any rolling 12-month period.

8.4. **Operations Log.** The permittee shall maintain a log of each time the emergency generator engine is operated. The log shall consist of the date and time the engine was started, the average operating load during that operating event and the date and time that operation ceased.

9. Recordkeeping and Reporting Requirements

9.1. Monthly Emission Calculation. By the tenth of each month, the permittee shall, using the data collected pursuant to the requirements of this permit, and using the most current and representative emissions data, calculate and record from each emissions unit, the monthly emissions of CO, NOx, PM, $PM_{2.5}$, PM_{10}, SO_2, volatile organic compounds (VOC), greenhouse gases (GHG) and HCl for the preceding month. Emissions calculated each month shall include emissions from startups, shutdowns, malfunctions and any other excess emissions.

9.2. Annual Emission Calculation. By the tenth of each month, the permittee shall calculate and record the rolling 12-month emissions of CO, NOx, PM, $PM_{2.5}$, PM_{10}, SO_2, VOC, GHG and HCl by using the monthly emissions calculated for the previous 12 months pursuant to Condition 9.1.

9.3. Notifications Prior to Facility Operation. At least 30 days prior to commencing operation of the facility, the permittee shall submit the following information to EPA:

9.3.1. Manufacturer's documentation that the DriAir 80 drift eliminator has a drift rate of no greater than 0.001% of water flow rate;

9.3.2. Manufacturer's documentation that the truck dump baghouse has an exhaust concentration no greater than 0.01 grains/dscf, and has a fan rated at no greater than 57,600 cfm.

9.3.3. Manufacturer's documentation that the screen building baghouse has an exhaust concentration no greater than 0.01 grains/dscf, and has a fan rated at no greater than 27,600 cfm.

9.3.4. Manufacturer's documentation that the boiler metering bin baghouse has an exhaust concentration no greater than 0.01 grains/dscf, and has a fan rated at no greater than 6,120 cfm.

9.3.5. Manufacturer's documentation that the ash handling and storage activities has an exhaust concentration no greater than 0.02 grains/dscf;

9.3.6. Manufacturer's documentation that the pneumatic conveyance fan for the ash handling and storage activities has a fan rated at no greater than 3,000 cfm;

9.3.7. Manufacturer's documentation that the limestone handling and storage activities baghouse has an exhaust concentration no greater than 0.02 grains/dscf, and has a fan rated at no greater than 720 cfm.

9.4. Additional Notifications. The permittee shall submit the following to EPA:

9.4.1. Postmarked within 15 days after it occurs, notification that construction of the facility has commenced (or restarted if ever stopped).

9.4.2. Postmarked within 15 days after any occurrence, notification that construction has been stopped (after commencing).

9.4.3. Postmarked within 15 days after it occurs, notification that initial startup of the boiler has occurred.

9.4.4. Postmarked within 15 days after it occurs, notification that the boiler has achieved the maximum production rate at which the boiler will be operated.

9.5. Deviation Reporting. Within 48 hours after discovery, the permittee shall report to EPA all emissions or operations that exceed or deviate from the requirements of this permit.

9.6. Semiannual Reports. Semiannually, no later than January 30 and July 30 of each year, a semiannual emissions report that includes the steam production data and monthly and 12-month rolling emissions data calculated per Conditions 9.1 and 9.2 for the previous six months (July thru December and January thru June, respectively). The raw data, calculations and assumptions shall be included with each semiannual emission report.

9.7. CERMS Reporting. The permittee shall submit the following to EPA:

9.7.1. At least 30 days prior to any CERMS accuracy determination required in Condition 2.18.6, notification of the planned date for performing the determination.

9.7.2. Within 60 days after completing the determination, three copies of a written report of the results of any CERMS accuracy determinations required in Condition 2.18.6.

9.8. Records Retention. All required records shall be kept on site for a period of five years and shall be made available to EPA upon request.

9.9. EPA Mailing Address. All submittals, notifications and reports to EPA shall be sent to:

Tribal NSR Permits Coordinator
U.S. EPA - Region 10, AWT-107
1200 Sixth Avenue, Suite 900
Seattle, WA 98101

10. Abbreviations and Acronyms

CERMS	Continuous emission rate monitoring system
cfm	Cubic feet per minute
CFR	Code of Federal Regulations
CGA	Cylinder gas audit
CO	Carbon monoxide
dscf	Dry standard cubic feet
EPA	United States Environmental Protection Agency (also U.S. EPA)
GHG	Greenhouse gases
lb/hr	Pounds per hour
NA	Not applicable
NOx	Nitrogen oxides
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than 2.5 microns
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
ppm	Parts per million
PSD	Prevention of significant deterioration
psig	Pounds per square inch gauge
RAA	Relative accuracy audit

RATA	Relative accuracy test audit
scfh	Standard cubic feet per hour
SO_2	Sulfur Dioxide
tpy	Tons per year
VOC	Volatile organic compound

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Technical Support Document
Non-Title V Air Quality Operating Permit

Project: PSD Avoidance Limits for New Electric Power Generation Facility

Oregon Bioenergy, LLC

Warm Springs Reservation
Warm Springs, Oregon

Purpose of Owner-Requested Non-Title V Operating Permit and Technical Support Document

Title 40 Code of Federal Regulations (CFR) Section 49.139 establishes a permitting program to provide for the establishment of Federally-enforceable requirements for air pollution sources located within Indian reservations in Idaho, Oregon and Washington. The owner or operator of an air pollution source who wishes to obtain a Federally-enforceable limitation on the source's actual emissions or potential to emit (PTE) must submit an application to the Regional Administrator requesting such limitation.

The United States Environmental Protection Agency (EPA) then develops the permit via a public process. The permit remains in effect until it is modified, revoked or terminated by EPA in writing.

This document, the Technical Support Document fulfils the requirement of 40 CFR § 49.139(c)(3) by describing the proposed limitation and its effect on the actual emissions and/or PTE of the air pollution source. Unlike the air quality operating permit, this document is not legally enforceable. The permittee is obligated to follow the terms of the permit. Any errors or omissions in the summaries provided here do not excuse the permittee from the requirements of the permit.

Table of Contents

1. EPA Authority to Issue Non-Title V Permits

On April 8, 2005, EPA adopted regulations (70 FR 18074) codified at 40 CFR Parts 9 and 49, establishing Federal Implementation Plans (FIPs) under the Clean Air Act for Indian reservations in Idaho, Oregon and Washington. The FIPs, commonly referred to as the Federal Air Rules for Reservations (FARR), put in place basic air quality regulations to protect health and welfare on Indian reservations located in the Pacific Northwest. 40 CFR § 49.139 creates a permitting program for establishing Federally-enforceable requirements for air pollution sources on Indian reservations. This permit has been developed pursuant to 40 CFR § 49.139.

2. General Information

2.1 Facility Location

Oregon Bioenergy, LLC, (permittee) is a privately owned and operated entity proposing to construct and operate this facility.

The facility will be located north of Warm Springs, Oregon, on a plateau, just south of Dry Creek (Latitude: 44° 47' 18.22" N, Longitude: 121° 13' 34.97"). The facility is located on the Warm Springs Reservation.

2.2 Local Air Quality and Attainment Status

Central Oregon, including the Warm Springs Reservation, either attains the national ambient air quality standard for all criteria pollutants or is unclassified. An area is unclassifiable when there is insufficient monitoring data.

2.3 Facility Operations

This facility will comprise the emission units shown in Table 1. The main emission unit at the facility will consist of a fluidized bed combustor and a waste heat boiler – referred to as a fluidized bed boiler that will be constructed by Energy Products of Idaho (EPI). The boiler will burn wood to produce steam to drive a conventional condensing steam turbine generator to produce a total of 42 MW and export 37 MW to the electric power grid. The FBB will include a sand bed that has air injected into it to "fluidize" the sand, and to provide a controlled combustion environment where the fuel will be burned. The boiler design is based on combusting a variety of woody biomass fuel blends, but the primary fuel will be tree trimmings and forest slash. The boiler will be compatible with fuel moisture contents ranging between 25 and 50 percent; the design value of the fuel is 4,805 British thermal units per pound (Btu/lb) at 40 percent moisture.

During boiler startup, ultra-low sulfur distillate fuel will be used to bring the sand bed up to temperature. The permittee estimates that each boiler startup sequence will require approximately 11,000 gallons of distillate over a 10-hour period. Boiler startup is not anticipated to occur more than three times a year. Use of the distillate fuel during startup will substantially reduce startup emissions compared with those boilers that rely only on wood during a startup. Furthermore, this technique enables the flue gas temperature to be high enough that pollution control equipment (SNCR, sorbent injection, and baghouse) would be effective by the time biomass is the primary fuel.

Table 1 – Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electrical Generation Plant
List of Emission Units

ID	Description	Make and Model	Rating[a]
OB-1	Fluidized Bed Boiler with steam turbine generator	Energy Products of Idaho No model designation – custom built for project site. Equipped with SNCR, multiclone, baghouse and acid gas control dry injection system.	518.4 MMBtu/hr with 4 distillate fuel burners, each rated at 50 MMBtu/hr
OB-2	Cooling Tower	EvapTech EC430-336K, Equipped with DriAir 80 Drift Eliminator	33,966 gal/min[b]
OB-3	Ash Storage and Handling Activities	Unspecified, equipped with three baghouses	Varies
OB-4	Ash Storage and Handling Activities	Unspecified, equipped with baghouse	Varies
OB-5	Limestone Storage and Handling Activities	Unspecified, equipped with baghouse	Varies
OB-6	Emergency Fire Pump Engine,	John Deere, JU6H-UFADP8 6-cylinder, turbocharged, raw water aftercooling, rated speed 1760 rpm	220 hp
OB-7	Emergency Generator Engine,	Cummins QSK60-G6 NR2 16 cylinder, turbocharged and low temperature aftercooled, rated speed 1800 rpm	2922 hp
OB-8	Diesel Fuel Tanks (four tanks)	NA	25,000, 2,500, 800 and 300 gallons
OB-9	Gasoline Fuel Tank	NA	1,000 gallons

a Permit conditions may limit operation to less than rated capacity.
b This flow rate is recirculated 6 times.

The heat produced from the fuel in the furnace will generate steam in water-filled boiler tubes located after the combustion zone. The boiler will be capable of producing up to 335,240 pounds per hour (lb/hr) of steam at 1,515 pounds per square inch absolute (psia) and 1,005 degrees Fahrenheit (°F). Hot flue gas leaving the steam generator will enter the multiclone, economizer, and air heater sections. The multiclone will use high efficiency cyclonic tubes to centrifugally remove ash particles from the gas stream. The economizer will be a single-pass, finned tube design. Flue gas flowing downward will de-entrain ash at the bottom of the unit. Downstream of the air heater, the flue gas continues on to additional emission control systems.

The boiler will be equipped with EPI's selective non-catalytic reduction (SNCR) system. In the EPI SNCR system, urea will be injected through multiple injection nozzles into the vapor space of the fluidized bed combustor where temperatures will be controlled to within the range of 1600 – 1800 °F. The urea solution, drawn from the bottom of the storage tank will be metered with a variable speed pump, controlled. The pump is controlled from 0-100% via a 4-20 mA signal from the NOX analyzer to supply the required amount of reagent for NOX abatement and to minimize ammonia slip. The number and location of the injection nozzles are designed to optimize injection velocities and distribution of the urea reagent into the reaction zone of the fluidized bed combustor. The system includes a 1,000 gallon liquid urea storage tank. Particulate in the gas stream is captured in a pulse-jet baghouse system located downstream of the SNCR and dry injection system. EPI anticipates the bags will be constructed of 16 ounce PPS Ryton.

For control of acid gas emissions, notably SO2 and HCl, a dry injection system will also be included ahead of the baghouse. This system will incorporate storage for a dry reagent – as yet unspecified but possibly hydrated lime, trona (trisodium hydrogendicarbonate dihydrate) or sodium bicarbonate. The storage will feed a hopper and metering device. The metered powder will be conveyed and injected into the flue gas ducting directly ahead of the baghouse inlet.

An induced-draft, counterflow cooling tower will be used to remove waste heat from the condenser cooling water. Constructed of fiberglass, the tower will be approximately 24 feet high and 130 feet long. Make-up water for the power plant will be supplied by a dedicated pump installed in the Warm Springs water system intake on the Deschutes River. The cooling tower will feature high-efficiency drift eliminators to reduce water loss and minimize emissions of all species of particulate matter.

Biomass fuel for the facility will be delivered by truck and off-loaded to a fuel storage and reclaim area. The fuel delivery trucks will drive onto a truck dumper platform which lifts the truck to unload the biomass. The truck dumper platform and hopper are enclosed and connected to a dust collection baghouse to control fugitive dust. The fuel is then conveyed via the stockout conveyor and discharged onto the fuel pile. A telescoping chute will be provided at the head end of the stockout conveyor to minimize the dust release from the fuel falling to the pile. The fuel will be reclaimed by an under-pile system onto a conveyor for transport to the boiler.

The fuel is screened prior to delivery to the boiler in the screen building. The screening process is enclosed in the screen building and connected to a dust collection baghouse to control fugitive dust. The discharge from the transfer conveyor into the boiler metering bins is also enclosed and connected to a dust collection baghouse. All conveyors will be covered to minimize the fugitive dust emissions.

In the fuel system, the delivery of the fuel from the truck into the hopper, the fuel dropping from the stockout conveyor to the storage pile, the pile reclaim and transfer to the boiler and the fuel screening area were all identified as potential emissions points.

Fuel deliveries are expected to occur no more than 12 hours per day and 6 days per week. However, emissions from the fuel dump baghouse are calculated based on continuous operation in order to avoid permit limits requiring monitoring of unloading operations. In addition, baghouses serving the screen building and metering bins are assumed to operate 8760 hours per year. The fuel handling process is expected to result in fugitive emissions. However, as fugitive emissions are not part of the PSD applicability determination for this source category, fugitive emissions are not estimated in this permit action.

Ash is generated in the boiler and is transported out of the boiler by combustion gases. The ash collects in various equipment downstream of the boiler. These equipment have provisions for the ash to be deposited in portions of the equipment where ash removal capability is part of the design. The facility will have a pneumatic collection system that provides continuous removal of ash from each discharge point, including all boiler, multiclone, economizer, air heater and baghouse collection points. The ash collected is delivered to the ash storage bin. The system consists of high pressure blowers which transports the ash to the storage tank. The system is completely covered. The storage tank is equipped with a bin vent, connected to a baghouse, to remove particulates prior to venting to the atmosphere. As ash is withdrawn from the storage system, for transport offsite, it is wetted to minimize emissions.

The limestone storage and handling activities consist of a storage bin, a pneumatic conveying system and the apparatus to deliver the limestone to the boiler. The storage bin is filled pneumatically from a selfunloading truck. The pneumatic transport air is exhausted through bin vents located at the top of the storage bin and to a baghouse positioned on top of the storage bin. The permittee has conservatively assumed a baghouse grain loading of 0.02 grains/cubic foot to calculate the PTE from this emissions unit. As baghouses are usually capable of performance at grain loading levels much lower than this, the proposed value was used in estimating emissions. Although the baghouse is only used when a truck is filling the silo, and the permittee estimates deliveries will take place twice per week and require three hours to unload the truck, emissions were calculated based on continuous operation. As needed, the limestone is transported to the boiler using an enclosed system comprised of a metered screw and an injection blower, where it is mixed with the fuel in the boiler.

The facility has an emergency fire pump that is powered by an internal combustion engine. Although use of the engine is for emergency use, in the event of a fire, the engine has to be tested on a weekly basis to ensure that it will be able to operate when required. In addition to the fire pump engine, the facility is equipped with an emergency generator, also powered by an engine. Intended only for use in emergency events where there are blackout conditions, this engine will also be tested on a weekly basis. To accommodate this testing usage, the permittee is requesting an annual operational limit of 100 hours for each engine.

There will be five fuel tanks at this facility. One tank will store gasoline for refueling purposes. A second tank will be used for diesel in a refueling capacity, while the remaining three tanks will be used for diesel to supply each of the engines and the boiler. Tank sizes are shown in Table 1.

The facility Standard Industrial Classification code is 4911 - Electric Services, Electric Power Generation

3. Description of Limits Requested

On March 7, 2011, EPA received an application for a non-Title V Operating Permit from Oregon Bioenergy. The submittal was supplemented by other information in response to questions posed by EPA - this supplemental application information was submitted primarily by email. In the non-Title V permit application, the permittee requested limits on emissions of NOx and CO to remain below the major source thresholds for these pollutants for PSD review. In addition, the application requested limits on the emissions of hydrogen chloride (HCl) to ensure that emissions of HCl remain below 10 tpy

4. Regulatory Analysis and Permit Content

4.1 Evaluation of Request for Limits to Avoid Major Source Construction Permitting

The Prevention of Significant Deterioration (PSD) permitting program, found in 40 CFR 52.21, is EPA's pre-construction review program for major sources of air pollution and major modifications to major stationary sources. As a wood-fired boiler is not one of the source categories listed in 40 CFR 52.21(b)(1)(i)(a), it is not subject to the 100 tons per year (tpy) PSD threshold. Consequently, this facility would be subject to PSD only if the PTE of a NSR regulated pollutant is above 250 tpy. PTE is based on a full year of operation at maximum capacity, considering emission limits if they are enforceable and reductions by control devices if they are required. Also, because a wood-fired boiler is not one of the source categories listed in 40 CFR 52.21(b)(1)(iii), fugitive emission are not counted towards PSD applicability.

The permittee did not provide uncontrolled PTE for the emission units at the facility. However, a quick assessment of emissions from the fluidized bed boiler, using AP-42 and based on continuous (i.e. 8760 hours per year) at maximum capacity (i.e. 518.4 MMBtu/hr), indicates that emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM), particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$) and particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) are over 700 tpy for each pollutant. In addition, continuous firing of diesel with the maximum sulfur content allowed under the FARR would indicate a PTE of sulfur dioxide (SO_2) in excess of 450 tpy. Volatile organic compound (VOC) emissions are estimated to be well below 250 tpy. In the absence of enforceable limits, construction of this facility would be considered a new source for PSD purposes, and a PSD permit would be required prior to construction of the facility. However, the permittee has elected to request enforceable limits for emissions of CO and NOx in order to reduce the PTE to below levels that would require PSD review. As noted above, the uncontrolled PTE for PM, $PM_{2.5}$, PM_{10} and SO_2 would require PSD review. Recognizing that this is not the permittee's intent, EPA has added enforceable limits for emissions of PM, $PM_{2.5}$, PM_{10} and SO_2. The PTE, reflecting enforceable conditions contained in the permit are shown in Table 2, below:

Table 2 – Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electrical Generation Plant
Facility PTE, tons/year (rounded to 0 decimal places)

	Air Pollutants								
Emission Unit ID	**CO**	**NOx**	**PM**	**$PM_{2.5}$**	**PM_{10}**	**SO_2**	**VOC**	**GHG[1]**	**Lead**
OB-1 – Fluidized Bed Boiler	205	226	37	37	37	35	21	806	< 1
OB-2 – Cooling Tower	0	0	1	1	1	0	0	0	0
OB-3 – Fuel Storage and Handling	0	0	34	34	34	0	0	0	0
OB-4 – Ash Storage and Handling	0	0	2	2	2	0	0	0	0
OB-5 – Limestone Storage and Handling	0	0	1	1	1	0	0	0	0
OB-6 – Emergency Fire Pump Engine	< 1	< 1	< 1	< 1	< 1	< 1	< 1	13	< 1
OB-7 – Emergency Generator Engine	< 1	2	< 1	< 1	< 1	< 1	< 1	160	< 1
OB-8 – Diesel Fuel Tanks	0	0	0	0	0	0	< 1	0	0
OB-9 – Gasoline Tank	0	0	0	0	0	0	< 1	0	0
TOTAL:	205	228	75	75	75	35	21	979	< 1

1 units for GHG are in tons on a CO_2e basis

Since the permittee will only be combusting wood, wood waste and forest residue, emissions of greenhouse gases (GHG), a regulated NSR pollutant, from the fluidized bed boiler qualify under the deferment specified in 40 CFR 52.21(b)(49)(ii)(a). GHG emissions from combustion of distillate and other plant activities are below the 100,000 tpy (CO_2e basis) threshold for consideration as a regulated NSR pollutant.

The permittee has not provided an uncontrolled PTE or a robust estimate of controlled PTE for emissions of hydrogen chloride (HCl). However, an enforceable emission limit can still provide the facility with the requested limit if accompanied by a robust means to assure that actual emissions can be accurately measured. There are no currently known emissions of HCl from combustion of distillate or the other activities at the facility. Consequently, an emission limit of 9.5 tpy should provide operational flexibility with an ability to account for additional sources of HCl.

4.2 Other Federal Regulations

EPA is obligated under the Endangered Species Act (ESA), Section 7, 16 U.S.C. §1531, to consider the impact that a federal project may have on listed species or critical habitats. The air emissions increase caused by this project will be less than the threshold for EPA's PSD permitting program, which is currently the only threshold EPA uses for requiring an ambient air quality impact analysis. For that reason, EPA concludes no adverse effect will be caused by air emissions. In some cases, the most likely impacts to threatened and endangered fish species will be from water discharges that are regulated under the National Pollutant Discharge Elimination System (NPDES). In this case, however, there will be no water discharges requiring a NPDES permit. The Department of Natural Resources of the Confederated Tribes of Warm Springs Reservation of Oregon conducted field surveys of the proposed project site and determined that no threatened or endangered plant or animal species were identified in the project area. Further, the survey concluded that there were no threatened or endangered fish species impacts associated with the project. Based on this determination, EPA concluded that the project would have no effect on a threatened or endangered specie or critical habitat. EPA's determination concludes EPA's obligations under Section 7 of the ESA (see Endangered Species Consultation Handbook: Procedures for Conducting Consultation and Conference Activities Under Section 7 of the Endangered Species Act, FWS and NMFS, March 1998, at Figure 1).

National Environmental Policy Act (NEPA) Review - Under Section 793(c) of the Energy Supply and Environmental Coordination Act of 1974, no action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969. This permit is an action taken under regulations implementing the Clean Air Act and is therefore exempt from NEPA.

National Historic Preservation Act (NHPA) – The permittee has been working with the Warm Springs Tribal Cultural Resources Office to identify and mitigate impacts to cultural resources.

Environmental Justice (EJ) - The proposed facility is located north of the town of Warm Springs. Links to maps that show environmental justice indicators for poverty and people of color are available on EPA's air permits website at this address: http://yosemite.epa.gov/R10/ocrej.nsf/environmental+justice/maps. For this permit action, EPA is seeking input regarding possible EJ concerns and whether the permittee's operation might cause a disproportionately high environmental or public health impact on a low income or minority population.

The permittee should be aware that this permit only addresses the emission limits (and related conditions) that are necessary to avoid PSD permitting requirements and to avoid being classified as a major source of HCl. The permit does not include other federal requirements that likely apply to this facility, including New Source Performance Standards (40 CFR Part 60), National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63), and the Federal Rules for Reservations (40 CFR Part 49). The permittee is responsible for compliance with all federal requirements that apply, whether or not they are in this non-Title V permit.

4.3 Permit Content

The permit includes the requested emission limits as well as monitoring, recordkeeping and reporting requirements necessary to assure compliance with the emission limits. Each section of the permit is discussed below.

Permit Section 1: General Conditions

Permit Condition 1.1 provides authorization for the permittee to construct and operate the facility as proposed – specifically the emission units identified in Table 1. This condition also requires the permittee to construct and operate the facility consistent with the representations made by the permittee in the permit application. Permit Condition 1.2 requires compliance with all the conditions within the permit. Permit Conditions 1.3 explains that the permit does not relieve the permittee from complying with any other rules or requirement that apply.

Permit Condition 1.4 carries the requirement of 40 CFR 52.21(r)(4) - . Boilers PH5 and PH6 must comply with the emission limits in this permit into the future to continue to avoid PSD. Relaxation of the emission or operational limits would require an assessment of whether PSD would apply as though initial construction had not yet commenced. Consistent with the PSD program, Permit Condition 1.5 renders this permit invalid if the permittee does not commence construction on the facility within 18 months of the permit's effective date or suspends construction efforts for a period of 18 months or more. Permit Condition 1.6 requires the permittee to maintain and operate all emission units and associated control equipment in a manner to minimize air emissions.

Permit Section 2: Fluidized Bed Boiler

Permit Conditions 2.1 and 2.2 establish emission limits on the fluidized bed boiler for NOx and CO, as requested by the permittee. In addition, Permit Condition 2.12 requires that the SNCR system be in operation at all times that the boiler is in operation in order to ensure that NOx emissions remain below the emission limit. Permit Condition 1.6 requires that the boiler and SNCR system be kept in good operating condition at all times. To assure that emissions of CO and NOx remain below the set emission limits, the permittee is required, in Permit Condition 2.18, to install, calibrate, maintain and operate a continuous emission rate monitoring system (CERMS) for CO and NOx. As all emission guarantees and resultant PTE for all pollutants, including GHG, are based on a fuel specification, Permit Condition 2.8 limits combustion of No. 2 distillate fuel to boiler startup and the biomass fuel to residue and waste from agricultural and forestry industries.

As noted in Section 4.1, EPA determined that uncontrolled emissions of PM, $PM_{2.5}$ and PM_{10} from the boiler would be in excess of 700 tpy for each of these pollutants. In order to remain below PSD applicability thresholds, these pollutants would also require emission limits, as provided in Permit Conditions 2.3, 2.4 and 2.5. In addition, Permit Condition 2.9 places an annual limit on boiler steam production, and Permit Condition 2.13 requires that at all times that the boiler is in operation, the boiler exhaust must be directed to the downstream control equipment that includes the equipment that reduces emissions of the various particulates – i.e. the multiclone and baghouse. Permit Condition 1.6 requires that the multiclone and baghouse be maintained in good operating condition at all times, to assure that emissions of PM, $PM_{2.5}$ and PM_{10} remain in compliance with the emission limits. Baghouse bag leaks are commonplace, are hard to detect and can result in greatly increased emissions. Consequently, Permit Condition 2.14 requires installation, operation and maintenance of a triboelectric bag leak detector to provide early warning of bag leaks.

EPA also determined that uncontrolled emissions of SO_2 from unlimited combustion of distillate fuel with the maximum fuel sulfur content allowed under the FARR would result in a PTE that exceeds PSD applicability thresholds. Consequently, this pollutant would also require emission limits, as provided in Permit Condition 2.6 in order for the project to avoid PSD review. To make this emission limit practically enforceable, Permit Condition 2.10 limits the quantity of distillate fuel that can be combusted in the boiler on an annual basis, and Permit Condition 2.11 limits the sulfur content of the fuel to 0.0015% by weight. In addition, Permit Condition 2.15 requires the permittee to install, maintain and operate a nonresettable, totalizing fuel meter to the boiler liquid fuel inlet in order to measure the amount of fuel combusted in the boiler. Permit Condition 2.16 requires the permittee to maintain records on each distillate fuel delivery and the sulfur content of each fuel delivery. This can be achieved by fuel vendor certification or by sampling and laboratory analysis.

The applicant has also requested an emission limit to keep PTE of hydrogen chloride (HCl) below 10 tpy. The application provided neither information on the mechanism of conversion of chlorides in the wood waste fuel to hydrogen chloride nor a robust proposal to assure that actual emissions of HCl would remain below the established emission limit of 9.5 tpy in Permit Condition 2.7 ,. Although Permit Conditions 2.13 and 1.6 require boiler exhaust to be directed to the acid-gas control dry injection system and that the dry injection system be maintained in good operating condition at all times, an additional requirement is necessary to assure that post-control emissions remain below the established HCl emission limit. As a result, Permit Condition 2.18 requires the permittee to install, calibrate, maintain and operate a CERMS for emissions of HCl.

This facility will need to apply for a Title V permit within a year of commencing operations. One of the purposes of a Title V permit is to ensure that monitoring and recordkeeping is adequate to assure compliance with the applicable requirements. Consequently, in this permit EPA will omit extensive ongoing compliance requirements with the intent to review operational and compliance data while developing a Title V permit. Permit Condition 2.17 requires the permittee to monitor certain operational parameters that would be relevant to an evaluation of compliance during development of a Title V permit.

As briefly mentioned earlier in this section, Permit Condition 2.18 requires the permittee to install and operate a continuous emission monitoring rate system to determine compliance with the CO, NOx and HCl emission limits. Both concentration (parts per million) and stack gas flow (must be measured so that pounds of pollutant per hour can be determined. Emissions of CO, NOx and HCl must be measured and recorded every hour that the boiler operates and summed every month for each pollutant to determine compliance with the 12-month rolling limit. As the application did not provide details on the design, installation, certification, calibration, maintenance and operation specifications for the CERMS, the permittee is required to submit a plan proposing exactly how they propose to implement the CERMS. The CERMS installed shall be as approved by EPA after a review of all relevant details. The CERMS specifications should be based on the continuous emission monitoring requirements for NSPS sources (see 40 CFR Part 60, Appendix B and F) and for acid rain program sources (see 40 CFR Part 75). The permittee is also required to develop a quality assurance plan for assuring the system meets the specifications in the permit. Because the permittee must account for emissions of each pollutant for every hour of operation, this condition requires the permittee to propose techniques for substituting alternative pollutant emission measurements or values when the monitoring system (either the concentration or flow rate monitoring devices) is not operating.

Permit Condition 2.19 assures that adequate access to stack testing locations and CERMS equipment is provided. Such access is most effectively designed into the facility before construction.

Permit Section 3: Cooling Tower

Permit Conditions 3.1 contains requirements to ensure that the drift eliminators are used whenever the cooling tower is in operation. Permit Condition 3.2 requires the permittee to select a drift eliminator that has a drift rate of no more than 0.001% of water flow rate. This will assure that the emissions from this emission unit remain below the PTE levels estimated in Appendix A. Permit Condition 3.3 requires the permittee to maintain an operating log to document the quantity and type of additives added to the cooling water stream. Actual emissions can then be calculated using these data.

Permit Section 4: Fuel Storage and Handling Activities

Permit Conditions 4.1, 4.2 and 4.3 contain requirements to ensure that the truck dump baghouse, the screen building baghouse and the metering bin baghouse are all in operation whenever the activities they are controlling are in operation. Permit Condition 4.4 requires selection of baghouses with an exhaust grain loading no greater than 0.01 grains/dscf. Similarly, Permit Condition 4.5 requires selection of baghouse fans with specified maximum ratings. These two conditions will assure that the emissions from this emission unit remain below the PTE levels estimated in Appendix A.

Permit Section 5: Ash Storage and Handling Activities

Permit Conditions 5.1 contains the requirement to ensure that the ash handling system baghouse is in operation whenever the boiler is in operation. Permit Condition 5.2 requires selection of a baghouse with an exhaust grain loading no greater than 0.02 grains/dscf, and selection of the ash conveyance fan with a specified maximum rating. This condition will assure that the emissions from this emission unit remain below the PTE levels estimated in Appendix A.

Permit Section 6: Limestone Storage and Handling Activities

Permit Conditions 6.1 contains the requirement to ensure that the limestone handling system baghouse is in operation whenever the limestone storage bin is being loaded. Permit Condition 6.2 requires selection of a baghouse with an exhaust grain loading no greater than 0.02 grains/dscf, and selection of a fan with a specified maximum rating. This condition will assure that the emissions from this emission unit remain below the PTE levels estimated in Appendix A.

Permit Section 7: Emergency Fire Pump Engine

Permit Conditions 7.1 and 7.2 contain the annual emission limits for NOx and CO respectively from this engine. Permit Condition 7.3 consist of the operational limit that makes the emission limits practically enforceable. Permit Condition 7.4 requires the permittee to maintain the operating logs to assure compliance with Permit Condition 7.3.

Permit Section 8: Emergency Generator Engine

Permit Conditions 8.1 and 8.2 contain the annual emission limits for NOx and CO respectively from this engine. Permit Condition 8.3 consist of the operational limit that makes the emission limits practically enforceable. Permit Condition 8.4 requires the permittee to maintain the operating logs to assure compliance with Permit Condition 8.3.

Permit Section 9: Recordkeeping and Reporting Requirements

Several permit conditions in Sections 2 through 8 require the permittee to monitor various aspects of facility operation. Permit Condition 9.1 requires the permittee to use this and other current and representative data, each and every month, to calculate the monthly emissions of CO, NOx, PM, PM2.5, PM10, SO2, VOC, GHG and HCl. Permit Condition 9.2 then requires the permittee to use the monthly emissions date calculated each month to determine the annual emissions on a rolling 12-month basis.

Information on the cooling tower drift eliminators and various baghouse data (exhaust concentration and fan ratings) were not finalized at the time of permit issuance. Since PTE for the cooling tower and the material handling activities depend on these specifications, the permittee is required, under Permit Condition 9.3, to provide confirmation of equipment specifications prior to facility startup. Permit Condition 9.4 requires the permittee to notify EPA of when construction on the facility has started (or restarted) or stopped. This condition also requires the permittee to notify EPA of the date of initial startup of the boiler and when it has achieved maximum production rate.

Permit Condition 9.5 requires the permittee to promptly report any deviations from permit conditions. Permit Condition 9.6 requires the permittee to semiannually to submit emission data calculated pursuant to

Permit Conditions 9.1 and 9.2. In addition, Permit Condition 9.7 requires the permittee to notify EPA of impending CERMS accuracy determinations and to provide copies of reports on the determinations.

Permit Condition 9.8 requires that permit records be maintained on site for at least 5 years, while Permit Condition 9.9 provides EPA's mailing address for permit-related correspondence and submittals.

5. Public Notice and Comment

As required under 40 CFR § 49.139(c), the draft operating permit was publicly noticed and made available for public comment as follows:

1. Made available for public inspection a copy of the draft operating permit prepared by EPA, the technical support document for the draft permit, the application, and all supporting materials at three locations: Jefferson County Library, at 241 SE 7th St., in Madras, OR, the Confederated Tribes of Warm Springs Administration Building at 1233 Veterans St., Warm Springs, OR and EPA's Regional Office in Seattle, WA (see 40 CFR 49.139(c)(5)(i)).
2. Published the public notice for this draft permit of the availability of the draft permit and supporting materials and of the opportunity to comment in a newspaper of general circulation in the area affected by the air pollution source - the Madras Pioneer. In addition, a notice was placed in the Spilyay Tymoo Tribal newspaper (see 40 CFR 49.139(c)(5)(ii)).
3. Provided copies of the notice to the owner or operator of the air pollution source, the Chairman of the Confederated Tribes of the Warm Springs Reservation, the Warm Springs Department of Natural Resources, and the Oregon Department of Environmental Quality(see 40 CFR 49.139(c)(5)(iii)).
4. Provided for a 30-day period for submittal of public comments, starting upon the date of publication of the notice (see 40 CFR 49.139(c)(5)(iv)).

The public comment period for this permit ran from December 21, 2011 to January 21, 2012. EPA received comments only from the permittee. As required under 40 CFR 49.139(c)(5)(iv) and (c)(6), EPA has considered the comments in preparing a final permit and technical support document and has documented a response to each comment below explaining whether any changes to the permit resulted and the reason the change was or was not made. As required under 40 CFR 49.139(c)(7), EPA will send the final permit and technical support document to each person who provided comments on the draft permit to operate and EPA will make available the final permit and technical support document at all of the locations where the draft permit was made available.

Response to comments from Oregon Bioenergy, LLC

Table 1 specifies that the boiler is equipped with four oil fired burners at 50 MMBtu/hour each. We acknowledge that a December 8, 2011 email to you identified this configuration. However, the boiler design team indicates there is also a 15 MMBtu/hr under-grate burner. Thus, the current design calls for five burners totaling 215 MMBtu/hour. While we regret this omission from the December 8 email to you, the conclusion in that email remains unchanged: emissions with oil firing during startup are lower than those during routine biomass operation. Despite the higher firing capacity, Oregon Bioenergy stands by its commitment to burning no more than 11,000 gallons of ultra-low sulfur distillate during startup. To allow for possible changes in burner configuration during final design, however, we prefer that the permit simply limit oil firing to 60,000 gallons per 12-month period (as in Condition 2.10) or, alternatively, to 215 MMBtu/hour during startup.

> EPA Response: EPA has updated the project emission inventory in Appendix A and has confirmed that this change does not affect the PSD applicability evaluations in the analysis for this permit. Therefore, the permit has been revised to reflect the revised distillate burner ratings. Revising the other condition as proposed by the permittee would serve to undermine one of the purposes of a pre-construction permit, which is to document exactly what activities and/or equipment are being authorized under the permit. In addition, this level of detail enhances compliance assurance efforts once the facility is constructed. No further change will be made to the permit as a result of this comment.

A table note to Table 1 implies the cooling tower is limited to cycling water six times. We assume this condition is intended to limit PM emissions from cooling tower drift. In the interest of reducing water consumption by the cooling tower, we propose to revise the condition to limit PM emissions to 0.603 tons per year by considering both dissolved solids and the number of cycles. The operator would monitor dissolved solids and cycles to calculate daily emissions that would support the annual emission calculation; for your convenience, we have copied Table 3 from our February 2011 application that identifies the PM calculation methodology. Thus, when dissolved solids are lower than the conservative value we used in our permit application, cooling water could be recycled more times; this would achieve the same PM emission rate while reducing water consumption and the demand on the evaporation ponds.

Table 3. Cooling Tower Particulate Matter Emission Rates

Water circulation rate (lpm)	120,542
Maximum total dissolved solids[1] (mg/l)	144
Number of recirculation cycles	6
Drift, fraction of circulating water	0.001%
$PM/PM_{10}/PM_{2.5}$ emission rate[1] (lb/hr)	0.138
$PM/PM_{10}/PM_{2.5}$ emission rate[2] (tpy)	0.603

1 120,542 lpm x 144 mg/l x 6 times concentration x 0.001% x 1 kg/10^6 mg x 2.2046 lb/kg x 60 min/hr

2 Based on continuous operation (8,760 hr/yr)

EPA Response: The footnote to Table 1 was intended to describe how the cooling tower would be operated – this is entirely consistent with how operations were described in the permit application. Operations as described in the comment letter could result in higher emissions. In fact, if the permittee seeks to operate the cooling tower in a manner different than described in the application, that may be accommodated through a permit revision. However, the permittee should be aware that the current, minimal monitoring regime will likely be expanded to address the increased flexibility sought, in order to assure compliance. No change will be made to the permit as a result of this comment.

Table 1, Conditions 3.1, 3.2, 9.3.1. Please eliminate the requirement to purchase a specific make and model of cooling tower and drift eliminator. We accept the requirements related to cooling tower throughput and drift rate but request flexibility in selecting specific makes and models. Aside from concerns about competitive bids, it is possible that a specific model of cooling tower or drift eliminator would no longer be available during procurement.

EPA Response: As noted earlier, one of the purposes of a pre-construction permit is to document exactly what activities and/or equipment are being authorized under the permit. In addition, this level of detail enhances compliance assurance efforts once the facility is constructed. No change will be made to the permit as a result of this comment.

Table 1. Please eliminate the requirement to purchase a specific make and model for the emergency generator. We accept a limit on the horsepower of the engine, but request flexibility in selecting a specific make and model. Aside from concerns about competitive bids, it is possible that a specific generator/engine combination would no longer be available during procurement.

EPA Response: As noted earlier, one of the purposes of a pre-construction permit is to document exactly what activities and/or equipment are being authorized under the permit. In addition, this level of detail enhances compliance assurance efforts once the facility is constructed. No change will be made to the permit as a result of this comment.

Conditions 2.1, 2.2. Given that the threshold for major source status is 250 tons and that CEMS are required to ensure emissions remain below that threshold, we propose annual limits of 245 tons NOx and 245 tons CO. This would still allow for engine testing while remaining less than the PSD threshold. We still expect actual emissions at or below the rates identified in our permit application (and as reflected in the permit), but request additional flexibility. In essence, we are asking for the same approach as EPA has taken with HCl emissions.

EPA Response: It should be noted that emissions of CO and NOx are primarily byproducts of combustion and that the combustion process is core to the boiler design – the boiler design is intended, in no small part, to minimize emissions of these pollutants. HCl, on the other hand, is not dependent on the mechanics of combustion. Instead it results from the conversion of chloride in the fuel. Control of HCl emissions is not designed into the boiler as it is with emissions of CO and NOx. In most permits, concern about flexibility centers around short-term emission limits (e.g. hourly limits). In this permit, there are no short-term limits, and the emission limits are based on vendor-sourced maximum emission rates, and on continuous operation at maximum loads. The permittee has provided no information on operational scenarios where operation beyond this basis is warranted. No change will be made to the permit as a result of this comment.

Condition 2.9. Given that CEMS are required to assure NOx and CO emissions are less than the major source threshold, we proposed that the annual steam production limit be removed.

EPA Response: The steam production limit serves as practically enforceable limits for SO_2, PM, PM_{10}, $PM_{2.5}$ as well as CO and NOx. No change will be made to the permit as a result of this comment.

Condition 2.12. Given that the permit requires CEMS to be employed to measure NOx, this condition is not required. EPI, the boiler designer, believes the fluidized bed boiler may be able to achieve the NOx emission rate without SNCR, at least under some conditions. If so, ammonia consumption and ammonia slip could be avoided. If EPA insists that the SNCR be functioning, the permit should require ammonia injection only when the temperature is sufficient for reactions to take place (i.e., not during startup or shutdown). We suggest the following revisions:

2.12. At all times when the fluidized bed is in operation *and the exhaust temperature has reached the temperature at which NOx reduction is effective*, the SNCR operation shall be in full operation

EPA Response: The permit application provided no basis for exemptions to this requirement. However, this comment indicates that periods of startup and shutdown may warrant exclusion from the requirement to operate the SNCR system. In following up with the permittee's consultant by email, it transpires that shutdowns occur quickly. A sudden shutdown could shut the boiler down immediately. However, a normal shutdown sequence would involve a reduction in load to about 30% followed by the shutdown. In either of these instances, the exhaust would remain hot and so, problems with ammonia slip are not expected. For startups, however, the equipment is relatively cold and will take time to achieve operating temperatures. During this time, the reagent may not be effective in removing NOx. The permittee's consultant has estimated startup time to be approximately 10 hours. This condition has been revised to excuse 10 hours per startup event.

Condition 2.13. This condition (and page 9 of the Technical Support Document) should refer to a dry injection system rather than an acid gas scrubber. There is no dedicated scrubber vessel.

EPA Response: All occurrences of "acid gas scrubber" have been replaced with "acid gas control dry injection system" in order to describe the process more accurately.

Condition 2.18.2.3 requires system adjustments when the daily low-level or high-level drift exceeds 2.5% of span. We have been advised that this performance criterion is acceptable for NOx and CO CEMS, for which significant operating experience is available. However, HCl CEMS are relatively new technology, and we have been advised to request the permit condition be revised to require adjustments when drift exceeds 5% of span.

EPA Response: EPA understands that there may be a need for additional flexibility for operation of the HCl continuous emission monitoring system and has revised this permit condition accordingly. However, the permittee should note that this does not preclude return to a lower value upon EPA's review of the facility's Title V permit application.

6.2 Limestone - eliminate "with" (typo)

EPA Response: This typographical error in the permit has been corrected as requested.

7. and 8. Emergency engines.

Although we may have suggested a 100 hour limit earlier, we believe an equally effective approach is to simply require that the engines be operated consistent with the definition of "emergency engine" in 40CFR60 Subpart IIII. This prohibits operation more than 100 hours except in an emergency. Given that Subpart IIII requires the owner to operate certified engines and no more than 100 hours, the emissions are fixed and there is no reason to impose annual emission limits. Thus, the only requirements for each engine would be to operate consistent with the definition of emergency engines under Subpart IIII and to maintain a log (as currently required under conditions 7.4 and 8.4).

EPA Response: This permit is issued to satisfy the obligations of the New Source Review program, and the conditions contained in this permit relate only to implementation of the New Source Review program. As has been described in the technical support document, this permit does not attempt to implement the requirements of any other program. No change will be made to this permit as a result of this comment.

6. Abbreviations and Acronyms

CERMS	Continuous emission rate monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
EPA	United States Environmental Protection Agency (also U.S. EPA)
EPI	Energy Products of Idaho
FARR	Federal Air Rules for Reservations
HCl	Hydrogen chloride
lb/hr	Pounds per hour
NOx	Nitrogen oxides
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than 2.5 microns
PM_{10}	Particulate matter with an aerodynamic diameter less than 10 microns
PSD	Prevention of significant deterioration
PTE	Potential to emit
SNCR	Selective non-catalytic reduction
SO2	Sulfur dioxide
tpy	Tons per year
VOC	Volatile organic compound

APPENDIX A

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Summary of Annual Emissions

Point Source Emissions

Unit ID	Description	Potential to Emit (tons/year) CO	NO_x	PM	$PM_{2.5}$	PM_{10}	SO_2	VOC	GHG[1]	Lead
OB-1	Fluidized Bed Boiler	205.23	225.76	36.94	36.94	36.94	34.89	20.52	806.44	0.01
OB-2	Cooling Tower			0.65	0.65	0.65				
OB-3	Fuel Storage and Handling Activities			34.28	34.28	34.28				
OB-4	Ash Storage and Handling Activities			2.25	2.25	2.25				
OB-5	Limestone Storage and Handling Activities			0.54	0.54	0.54				
OB-6	Emergency Fire Pump Engine	0.02	0.07	0.00	0.00	0.00	0.00	0.00	12.64	0.00
OB-7	Emergency Generator Engine	0.18	1.71	0.05	0.05	0.05	0.00	0.07	159.51	0.00
OB-8	Diesel Fuel Tanks[2]							0.01		
OB-9	Gasoline Tank[3]							0.09		
	Total Point Source Emissions:	205.44	227.53	74.73	74.73	74.73	34.89	20.69	978.59	0.01

Notes

1 Emissions of GHG are in tons of CO_2e and exclude emissions from biomass combustion.
2 This emission unit consists of four diesel tanks. Emissions estimates are detailed in attachments to email from Environ dated 10/28/2011
3 This emission unit consists of one gasoline tank. Emissions estimates are detailed in attachments to email from Environ dated 10/28/2011

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit:	OB-1 Fluidized Bed Boiler
Make/Model[1]:	Custom built for project by Energy Products of Idaho
Maximum Hourly Rating[1]:	518.4 MMBtu/hr
Maximum Hourly Rating[1]:	352,002 lbs/hr
Control Equipment:	SNCR, multiclone and baghouse
Fuel:	Biomass/wood waste

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily[2] (MMBtu)	Annual[2] (MMBtu)		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	0.10	lb/MMBtu	11,808	4,104,673		51.84	1181	205.23	6.532	6.199	5.904
NO_x	0.11	lb/MMBtu	11808	4,104,673	Included in	57.024	1299	225.76	7.185	6.819	6.494
PM	0.02	lb/MMBtu	11808	4,104,673	emission	9.3312	213	36.94	1.176	1.116	1.063
$PM_{2.5}$	0.018	lb/MMBtu	11808	4,104,673	factor	9.3312	213	36.94	1.176	1.116	1.063
PM_{10}	0.018	lb/MMBtu	11808	4,104,673		9.3312	213	36.94	1.176	1.116	1.063
SO_2	0.017	lb/MMBtu	11808	4,104,673		8.8128	201	34.89	1.11E+00	1.05E+00	1.00E+00
VOC	0.010	lb/MMBtu	11808	4,104,673		5.184	118	20.52	6.53E-01	6.20E-01	5.90E-01
Lead	0.00000449	lb/MMBtu	11808	4,104,673		2.33E-03	5.30E-02	0.01	2.93E-04	2.78E-04	2.65E-04

Emissions Factor References

CO	Manufacturer guarantee per attachment to e-mail of 11/25/2011 from Environ
NO_x	Manufacturer guarantee per attachment to e-mail of 11/25/2011 from Environ
PM	Assumed to be same as PM10 (including condensible portion)
$PM_{2.5}$	Assumed to be the same as for PM_{10}
PM_{10}	Manufacturer guarantee per attachment to e-mail of 11/25/2011 from Environ
SO_2	Manufacturer guarantee per att‹ 0.000015 by weight
VOC	Manufacturer guarantee per attachment to e-mail of 11/25/2011 from Environ
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-24, Table 5-

Fuel:	Liquid distillate, #2
Maximum Hourly Rating[3]:	215 MMBtu/hr
Maximum Hourly Fuel Use[4]:	1,558 gallons/hour

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation		Control Efficiency[5]	Potential to Emit			Potential to Emit in g/sec		
			Daily (gal)	Annual (gal)		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	5	$lb/10^3$ gal	15000	60,000		7.79	75	0.15	0.982	0.394	0.004
NO_x	24	$lb/10^3$ gal	15000	60,000		37.39	360	0.72	4.711	1.89	0.021
PM	2	$lb/10^3$ gal	15000	60,000		3.12	30	0.06	0.393	0.157	0.002
$PM_{2.5}$	1.54	$lb/10^3$ gal	15000	60,000		2.40	23.1	0.05	0.302	0.121	0.001
PM_{10}	2.30	$lb/10^3$ gal	15000	60,000		3.58	34.5	0.07	0.451	0.181	0.002
SO_2	0.2130	$lb/10^3$ gal	15000	60,000		0.33	3.195	0.01	4.18E-02	1.68E-02	1.84E-04
VOC	0.76	$lb/10^3$ gal	15000	60,000		1.18	11.4	0.02	1.49E-01	5.98E-02	6.56E-04
Lead	0.000009	lb/MMBtu	15000	60,000		1.94E-03	1.86E-02	7.45E-02	2.44E-04	9.78E-05	2.14E-03

Emissions Factor References

CO	AP-42, Table 1.3-1
NO_x	AP-42, Table 1.3-1
PM	AP-42, Table 1.3-1
$PM_{2.5}$	AP-42, Tables 1.3-2 and 13-6
PM_{10}	AP-42, Tables 1.3-2 and 13-6
SO_2	AP-42, Table 1.3-1 Sulfur content of fuel: 0.0015 %
VOC	AP-42, Table 1.3-3
Lead	AP-42, Table 1.3-10

Conversions Used

2,000 lbs/ton
138000 Btu/gallon[6]

Footnotes/Assumptions

1 Boiler specification per 11/25/2011 e-mail and attachments from Environ
2 Boiler rating per permit application received 3/7/2011
3 Distillate burner specification per 12/08/2011 e-mail and attachments from Environ, and permittee public comments letter of 1/20/2012
4 Fuel usage for boiler start-up based on application received on 3/7/2011 and on burner rating.
Fuel volumes have been increased to provide additional flexibility.
5 Although emissions reductions can be expected from in-place boiler controls, distillate combustion emissions calculated as uncontrolled
6 Fuel heat content from 40 CFR Part 98, Subpart C, Table C-1

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit:	OB-2	Cooling Tower
Make/Model[1]:	EvapTech EC430-336K	
Fuel:	NA	
Rating[1]:	235.6	MMBtu/h (Design heat load)
Maximum Operating Level[1]:	33,966	gallons per minute
Number of Recirculation Cycles[1]:	6	
Control Equipment:	DriAir 80 Drift Eliminator	

Pollutant	Emission Factors	Emission Factor Units	Maximum Hours of Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily	Annual		Hourly, lb/hr	Daily, lb/day	Annual, tpy	One-Hour	24-Hour	365-Day
CO	-	-	24	8760							
NO_x	-	-	24	8760							
PM	1.1	grams/min	24	8760	included in	0.15	3.58	0.65	0.019	0.019	0.019
$PM_{2.5}$	1.1	grams/min	24	8760	emission	0.15	3.58	0.65	0.019	0.019	0.019
PM_{10}	1.1	grams/min	24	8760	factor	0.15	3.58	0.65	0.019	0.019	0.019
SO_2	-	-	24	8760							
VOC	-	-	24	8760							
Lead	-	-	24	8760							

Emissions Factor References

CO	No known emissions of this pollutant from this source category.
NO_x	No known emissions of this pollutant from this source category.
PM	Emission factor based on water flowrate[2], drift rate[3], total dissolved solids[4],
$PM_{2.5}$	Assumed to be same as for PM
PM_{10}	Assumed to be same as for PM
SO_2	No known emissions of this pollutant from this source category.
VOC	No known emissions of this pollutant from this source category.
Lead	No known emissions of this pollutant from this source category.

Conversions Used

453.59 g/lb
2,000 lbs/ton
745.7 watts/hp
0.26418 gal/liter

Footnotes/Assumptions

1 Specifications per March 4 permit application

2 Water flowrate based on maximum flow and recirculation cycles: 203796 gallons per minute
771428.571 liters/minute

3 Drift rate: 0.001% of water flow rate
Conservative assumption by permittee based on best possible performance from drift eliminator per email dated 11/21/2011 from E Hansen (Environ) to P Nair (EPA)

4 Maximum total dissolved solids: 146.3 milligram/liter
Based on aggregate of naturally occurring solids and maximum additives per email dated 11/21/2011 from E Hansen (Environ) to P Nair (EPA)

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit: OB-3 Fuel Storage and Handling Activities
Make/Model: NA
Rating: NA
Maximum Hourly Fuel Use: NA
Control Equipment: Baghouses - exact models and specifications not currently available

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation Daily (hrs)	Maximum Operation Annual[1] (hrs)	Control Efficiency	Potential to Emit Hourly lb/hr	Potential to Emit Daily lb/day	Potential to Emit Annual tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
All Three Emission Points											
CO	-	-	24	8,760							
NO_x	-	-	24	8760							
SO_2	-	-	24	8760							
VOC	-	-	24	8760							
Leaad	-	-	24	8760							
Truck Dump Baghouse											
PM	4.94	lbs/hr	24	8760	included in	4.94	118.49	21.62	0.622	0.622	0.622
$PM_{2.5}$	4.94	lbs/hr	24	8760	emission factor	4.94	118.49	21.62	0.622	0.622	0.622
PM_{10}	4.94	lbs/hr	24	8760		4.94	118.49	21.62	0.622	0.622	0.622
Screen Building Baghouse											
PM	2.37	lbs/hr	24	8760	included in	2.37	56.78	10.36	0.298	0.298	0.298
$PM_{2.5}$	2.37	lbs/hr	24	8760	emission factor	2.37	56.78	10.36	0.298	0.298	0.298
PM_{10}	2.37	lbs/hr	24	8760		2.37	56.78	10.36	0.298	0.298	0.298
Boiler Metering Baghouse											
PM	0.52	lbs/hr	24	8760	included in	0.52	12.59	2.30	0.066	0.066	0.066
$PM_{2.5}$	0.52	lbs/hr	24	8760	emission factor	0.52	12.59	2.30	0.066	0.066	0.066
PM_{10}	0.52	lbs/hr	24	8760		0.52	12.59	2.30	0.066	0.066	0.066

Emissions Factor References

CO	No known emissions of this pollutant from this source category.
NO_x	No known emissions of this pollutant from this source category.
PM	Emissions based on exhaust grain loading[2] and baghouse fan rating[3]
$PM_{2.5}$	Assumed to be same as for PM
PM_{10}	Assumed to be same as for PM
SO_2	No known emissions of this pollutant from this source category.
VOC	No known emissions of this pollutant from this source category.
Lead	No known emissions of this pollutant from this source category.

Conversions Used

453.59 g/lb
2,000 lbs/ton
7000 grains/lb

Footnotes/Assumptions

1 Continuous use was conservatively assumed for all baghouse operation.
2 Baghouse exhaust grain loading per 11-23-2011 e-mail: 0.01 grains/dscf
3 The 11/23/2011 e-mail from Environ suggests the following baghouse fan ratings:

Truck dump baghouse:	48000 cfm
Screen Building Baghouse:	23000 cfm
Boiler Metering Baghouse:	5100 cfm

To provide flexibility in fan selection, value used here is 20% higher:

Truck dump baghouse:	57600 cfm
Screen Building Baghouse:	27600 cfm
Boiler Metering Baghouse:	6120 cfm

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit: OB-4 Ash Storage and Handling Activities
Make/Model: NA
Rating: NA
Maximum Hourly Fuel Use: NA
Control Equipment: Baghouse - exact model and specifications not currently available

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation Daily (hrs)	Maximum Operation Annual[1] (hrs)	Control Efficiency	Potential to Emit Hourly lb/hr	Potential to Emit Daily lb/day	Potential to Emit Annual tpy	Potential to Emit in g/sec One-Hour	Potential to Emit in g/sec 24-Hour	Potential to Emit in g/sec 365-Day
CO	-	-	24	8,760							
NO_x	-	-	24	8760							
PM	0.51	lbs/hr	24	8760	included in emission factor	0.51	12.34	2.25	0.065	0.065	0.065
$PM_{2.5}$	0.51	lbs/hr	24	8760		0.51	12.34	2.25	0.065	0.065	0.065
PM_{10}	0.51	lbs/hr	24	8760		0.51	12.34	2.25	0.065	0.065	0.065
SO_2	-	-	24	8760							
VOC	-	-	24	8760							
Lead	-	-	24	8760							

Emissions Factor References

CO	No known emissions of this pollutant from this source category.
NO_x	No known emissions of this pollutant from this source category.
PM	Emissions based on exhaust grain loading[2] and baghouse fan rating[3]
$PM_{2.5}$	Assumed to be same as for PM
PM_{10}	Assumed to be same as for PM
SO_2	No known emissions of this pollutant from this source category.
VOC	No known emissions of this pollutant from this source category.
Lead	No known emissions of this pollutant from this source category.

Conversions Used

453.59 g/lb
2,000 lbs/ton
7000 grains/lb

Footnotes/Assumptions

1 Operation is expected to be continuous.
2 Baghouse exhaust grain loading per 11-23-2011 e-mail: 0.02 grains/dscf
3 The 11/23/2011 e-mail from Environ suggests a baghouse fan rating of : 2500 cfm
To provide flexibility in fan selection, value used here is 20% higher: 3000 cfm

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit:	OB-5	Limestone Storage and Handling Activities
Make/Model:	NA	
Rating:	NA	
Maximum Hourly Fuel Use:	NA	
Control Equipment:	Baghouse - exact model and specifications not currently available	

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation		Control Efficiency	Potential to Emit			Potential to Emit in g/sec		
			Daily (hrs)	Annual[1] (hrs)		Hourly lb/hr	Daily lb/day	Annual tpy	One-Hour	24-Hour	365-Day
CO	-	-	24	8,760							
NO_x	-	-	24	8760							
PM	0.12	lbs/hr	24	8760	included in emission factor	0.12	2.96	0.54	0.016	0.016	0.016
$PM_{2.5}$	0.12	lbs/hr	24	8760		0.12	2.96	0.54	0.016	0.016	0.016
PM_{10}	0.12	lbs/hr	24	8760		0.12	2.96	0.54	0.016	0.016	0.016
SO_2	-	-	24	8760							
VOC	-	-	24	8760							
Lead	-	-	24	8760							

Emissions Factor References

CO	No known emissions of this pollutant from this source category.
NO_x	No known emissions of this pollutant from this source category.
PM	Emissions based on exhaust grain loading[2] and baghouse fan rating[3]
$PM_{2.5}$	Assumed to be same as for PM
PM_{10}	Assumed to be same as for PM
SO_2	No known emissions of this pollutant from this source category.
VOC	No known emissions of this pollutant from this source category.
Lead	No known emissions of this pollutant from this source category.

Conversions Used

453.59 g/lb
2,000 lbs/ton
7000 grains/lb

Footnotes/Assumptions

1 Although permittee estimates only 312 hours of of loading activities per year, continuous has been assumed for PTI
2 Baghouse exhaust grain loading per 11-23-2011 e-mail: 0.02 grains/dscf
3 The 11/23/2011 e-mail from Environ suggests a baghouse fan rating of : 600 cfm
To provide flexibility in fan selection, value used here is 20% higher: 720 cfm

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit:	OB-6	Emergency Fire Pump Engine
Make/Model[1]:	John Deere JU6H-UFADP8	
Fuel:	No. 2 Diesel Fuel	
Rating[1]:	220 hp	(164 kW)
Maximum Hourly Fuel Use[1]:	11.2 gal/hour	
Control Equipment[1]:	Tier 3 Engine	

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[2, 3] Daily (hrs)	Maximum Operation Annual (hrs)	Control Efficiency	Potential to Emit Hourly, lb/hr	Potential to Emit Daily, lb/day	Potential to Emit Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
CO	0.9	g/hp-hr	24	100		0.44	10.56	0.02	0.055	0.055	0.001
NO_x	2.7	g/hp-hr	24	100		1.31	31.44	0.07	0.165	0.165	0.002
PM	0.15	g/hp-hr	24	100		0.07	1.68	0.00	0.009	0.009	0.000
$PM_{2.5}$	0.15	g/hp-hr	24	100		0.07	1.68	0.00	0.009	0.009	0.000
PM_{10}	0.15	g/hp-hr	24	100		0.07	1.68	0.00	0.009	0.009	0.000
SO_2	0.000213	lb/gal	24	100		2.38E-03	0.06	0.00	0.000	0.000	0.000
VOC	0.1	g/hp-hr	24	100		0.05	1.2	0.00	0.006	0.006	0.000
Lead	0.000029	lb/MMBtu	24	100		4.48E-05	1.08E-03	2.24E-06	0.000	0.000	0.000

Emissions Factor References

CO	Based on manufacturer data transmitted via e-mail 10/28/11
NO_x	Based on manufacturer data transmitted via e-mail 10/28/11
PM	Based on manufacturer data transmitted via e-mail 10/28/11
$PM_{2.5}$	Based on manufacturer data transmitted via e-mail 10/28/11
PM_{10}	Based on manufacturer data transmitted via e-mail 10/28/11
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	Based on manufacturer data transmitted via e-mail 10/28/11
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Physical Data and Conversions Used

453.59 g/lb	
2,000 lbs/ton	
745.7 watts/hp	
0.138 MMBtu/gallon	Heat content of diesel fuel (Part 98, Subpart C, Table C1)
7.09 lbs/gallon	Density of diesel fuel

Footnotes/Assumptions

1 Engine specification per email dated 10/28/2011 from Environ
2 Daily maximum operation is based on maximum daily allowable hours of operation
3 Annual maximum per email dated 10/28/2011 from Environ

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
Criteria Pollutant Potential to Emit Emission Inventory

Emissions Unit:	OB-7 Emergency Generator Engine
Make/Model[1]:	Cummins QSK60-G6 NR2
Fuel:	No. 2 Diesel Fuel
Rating[1]:	2,922 hp (2179 kW)
Maximum Hourly Fuel Use[1]:	141.3 gal/hour
Control Equipment[1]:	Tier 2 Engine

Pollutant	Emission Factors	Emission Factor Units	Maximum Operation[2, 3] Daily (hrs)	Annual (hrs)	Control Efficiency	Potential to Emit Hourly, lb/hr	Daily, lb/day	Annual, tpy	Potential to Emit in g/sec One-Hour	24-Hour	365-Day
CO	0.57	g/hp-hr	24	100		3.67	88.08	0.18	0.462	0.462	0.005
NO_x	5.30	g/hp-hr	24	100		34.14	819.36	1.71	4.302	4.302	0.049
PM	0.16	g/hp-hr	24	100		1.03	24.72	0.05	0.13	0.13	0.001
$PM_{2.5}$	0.16	g/hp-hr	24	100		1.03	24.72	0.05	0.13	0.13	0.001
PM_{10}	0.16	g/hp-hr	24	100		1.03	24.72	0.05	0.13	0.13	0.001
SO_2	0.000213	lb/gal	24	100		3.01E-02	0.72	0.00	0.004	0.004	0.000
VOC	0.22	g/hp-hr	24	100		1.42	34.08	0.07	0.179	0.179	0.002
Lead	0.000029	lb/MMBtu	24	100		5.65E-04	1.36E-02	2.83E-05	0.000	0.000	0.000

Emissions Factor References

CO	Based on manufacturer data transmitted via e-mail 10/28/11
NO_x	Based on manufacturer data transmitted via e-mail 10/28/11
PM	Based on manufacturer data transmitted via e-mail 10/28/11
$PM_{2.5}$	Based on manufacturer data transmitted via e-mail 10/28/11
PM_{10}	Based on manufacturer data transmitted via e-mail 10/28/11
SO_2	Sulfur content of fuel: 0.000015 by weight
VOC	Based on manufacturer data transmitted via e-mail 10/28/11
Lead	Locating and Estimating Air Emissions from Sources of Lead and Lead Compounds, EPA-454/R-98-006, May 1998, page 5-45

Physical Data and Conversions Used

453.59 g/lb	
2,000 lbs/ton	
745.7 watts/hp	
0.138 MMBtu/gallon	Heat content of diesel fuel (Part 98, Subpart C, Table C1)
7.09 lbs/gallon	Density of diesel fuel

Footnotes/Assumptions

1 Engine specification per email dated 10/28/2011 from Environ

2 Daily maximum operation is based on maximum daily allowable hours of operation

3 Annual maximum per email dated 10/28/2011 from Environ

Oregon Bioenergy, LLC
Warm Springs Biomass-Fired Electric Power Generation Plant
GHG Potential to Emit Emission Inventory

Emissions Unit:	OB-1 to 9	
Global Warming Potential:	CO_2	1
	N_2O	310
	CH_4	21

Point Source Emissions

Unit ID	Description	Maximum Annual Capacity		Emission Factors[1,2]			Potential to Emit (tpy)			
				CO_2	N_2O	CH_4	CO_2	N_2O	CH_4	CO_2e
OB-1	Fluidized Bed Boiler (biomass combustion)	4,104,673	MMBtu	93.80	4.2E-03	3.2E-02	424,412	19	145	433,344
OB-1	Fluidized Bed Boiler (diesel combustion)	60,000	gallons	73.96	6.E-04	3.E-03	675	0.01	0.03	677
OB-1	Fluidized Bed Boiler (limestone)	586920	lbs	0.44	0.00	0.00	129.12	0.00	0.00	129
OB-6	Emergency Fire Pump Engine	1120	gallons	73.96	6.E-04	3.E-03	13	0.00	0.00	13
OB-7	Emergency Generator Engine	14130	gallons	73.96	6.E-04	3.E-03	159	0.00	0.01	160
The following emission units have no known emissions of GHG:										
OB-2	Cooling Tower									
OB-3	Fuel Storage and Handling Activities									
OB-4	Ash Storage and Handling Activities									
OB-5	Limestone Storage and Handling Activities									
OB-8	Diesel Fuel Tanks[2]									
OB-9	Gasoline Tank[3]									

Total from biomass combustion: 433,344

Total from non-biomass-combustion sources: 979

Physical Data and Conversions Used

453.59 g/lb
2,000 lbs/ton
0.138 MMBtu/gallc Heat content of diesel fuel (Part 98, Subpart C, Table C1)

Footnotes/Assumptions

1 Emission factors for wood waste and distillate are in units of kg/MMBtu
Emission factors are from 40 CFR Part 98 Subpart C, Tables C-1 and C-2
2 Emission of CO_2 from limestone is based on stoichiometric ratio of limestone use and conversion to CO_2 - 0.44